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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2016 TRHOUGH MAY 31, 2017.	**CASE NO. IPC-E-16-08** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's Application to increase its revenues through the Power Cost Adjustment ("PCA") mechanism. The comments are divided into four main sections: (1) Summary of Application; (2) Staff Audit and Analysis; (3) Customer Relations; and (4) Staff Recommendations.

I. SUMMARY OF APPLICATION

On April 15, 2016, Idaho Power Company (the "Company") filed its annual PCA Application. The Company asks to increase its total revenue by about $17.3 million, or 1.57% more than its current billed revenue. The following summarizes the Company's proposal:

Table 1: Idaho Power Proposed Customer Revenue Impact

Description	Current ($)	Proposed ($)	Difference ($)	% of increase
PCA Future Forecast	39,299,591	47,770,774	8,471,183	49%
PCA True Up (includes reconciliation of true-up)	34,652,303	38,587,844	3,935,541	23%
Associated DSM Rider Change	(3,991,365)	(3,970,036)	21,329	0%
Allocated Revenue Sharing	(8,048,717)	(3,159,478)	4,889,239	28%
PCA total	61,911,812	79,229,104	**17,317,292**	100%
Total Billed Revenue	1,103,115,547	1,120,432,839	**17,317,292**	1.57%

As shown above, the Company attributes 49% of its proposed $17.3 million revenue increase to an $8.5 million increase in the PCA future forecast. The remaining increase is due to a $4.8 million reduction in revenue sharing and a $3.9 million increase in the PCA true-up. A copy of Company Attachment 2 showing the impact of proposed rates by customer class is included as Attachment C to these comments. The overall proposed increase is further described below. The Company proposes that the rate changes take effect June 1, 2016.

A. Proposed PCA Rate Increase

This year, the Schedule 55 PCA rate for each class combines the PCA's three traditional components (forecast, "true-up," and reconciliation) with two additional components: the Demand Side Management ("DSM") Rider credit and Revenue Sharing. The five components are described below.

1. Traditional PCA Components

The traditional annual PCA mechanism has three components: a) a "forecast" or projection that estimates the difference between net power supply expense ("NPSE") embedded in base rates and the coming year's NPSE; b) a "true-up" that captures the difference between actual and base NPSE and credits the revenue from the previous year's forecast rate; and c) a reconciliation of the prior year's true-up that captures any under-recovered or under-refunded true-up amount. This is also called the true-up of the true-up.

The Company combines the three traditional PCA rate components to propose a 2016/2017 PCA rate surcharge of 0.6187 cents per kilowatt-hour (¢/kWh) (i.e., 0.3422 + 0.3129 - 0.0364). The Company expects this rate will allow it to recover traditional PCA costs in one year. The proposed rate is 0.0782 ¢/kWh higher than current PCA rate. Each component is described in more detail below.

a. Forecast

The Company uses its March 31, 2016 Operating Plan to forecast NPSE for the coming year and determines the difference between these amounts and NPSE embedded in base rates. The Company reports Idaho ratepayers' share of the difference is about $47.8 million. This difference is then converted into a ¢/kWh rate by dividing the amount by projected energy sales. The Company has proposed a 0.3422 ¢/kWh forecast rate as compared to a 0.2815 ¢/kWh rate in last year's PCA.

b. True-Up

The true-up amount is the difference between: (1) actual and base NPSE, and (2) revenues from the forecast rate that accrued during the prior year. The prior year's PCA amount is not precisely recovered, because the expected-cost forecast is never 100% accurate. The Company converts the true-up amount to a ¢/kWh rate by dividing it by projected energy sales. The Company calculates Idaho ratepayers' share of the true-up amount to be $43.7 million, and expects to recover that amount through a true-up rate of 0.3129 ¢/kWh as compared to last year's rate of 0.2483 ¢/kWh. A copy of Company Exhibit 1, which details the Company's true-up calculations, is reproduced as Attachment A to these comments.

c. Reconciliation of the True-Up

The reconciliation of the true-up tracks the recovery of the prior year's true-up amounts. It nets the actual revenue collected from the true-up rates and revenue-sharing rates against the amounts set for recovery. Any difference is carried into the next year's true-up reconciliation, along with the true-up difference. According to the Company, the true-up was over-collected by about $5.1 million, resulting in a proposed reconciliation of the true-up rate credit of 0.0364 ¢/kWh as compared to a rate surcharge of 0.0107 ¢/kWh in last year's PCA.

2. Additional PCA Components

Besides the three traditional components discussed above, this year's PCA includes the DSM Rider adjustment and Revenue-Sharing components discussed below.

a. DSM Rider Adjustment

The Company continues to apply a $4.0 million DSM Rider credit to the PCA, resulting in a 0.0284 ¢/kWh rate credit. This revenue credit assures that the change to base level NPSE approved in March 2014 by Order No. 33000 remains revenue neutral. The credit is applied on a uniform basis to each customer class, and will continue to be included in annual PCAs until NPSE included in base rates is re-established as part of a general rate case.

b. Revenue Sharing

The Company states its 10.13% year-end Return on Equity ("ROE") will directly reduce PCA rates by $3.2 million effective June 1, 2016. The Company proposes to spread the Revenue-Sharing amount to the Company's rate schedules on a uniform percent of base revenue basis, and to assign it to the energy rates in each schedule. This class-specific energy credit combines the traditional PCA, DSM Rider Adjustment, and Revenue Sharing into one energy rate for each rate schedule.

B. Company's Rate Calculation

Schedule 55 rates include all the rate changes proposed in this filing. Company Exhibit No. 2, reproduced as Attachment B in these comments, illustrates the proposed combined Schedule 55 rates by customer class (column F). It also breaks down the overall Schedule 55 rates by: (1) Revenue Sharing rates in column C, (2) allocated DSM Rider rates in column D, and (3) traditional PCA rates in column E.

II. STAFF AUDIT AND ANALYSIS

A. Staff's Analysis of PCA Rates

Staff analyzed the traditional PCA components (forecast, true-up, and reconciliation) and additional components applied in this case (DSM Rider Adjustment and Revenue Sharing). In summary, Staff believes that the Company complied with past Commission orders and accurately calculated all proposed PCA components. Staff's analysis of the PCA components is as follows.

1. Traditional PCA Components

a. The Forecast

The forecast rate accounts for 49%, or $8.47 million of the $17.32 million projected revenue increase from the Company's proposed Schedule 55 rates as illustrated in Table 1 above. The Company uses its March 31, 2016 Operating Plan to forecast the difference between NPSE embedded in base rates and NPSE the Company expects to recover in the coming year. Table 2, below, summarizes the differences by account between next year's forecast and current NPSE in base rates. Staff thoroughly reviewed the Company's Operating Plan, including assumptions used to develop the forecast. Based on its analysis, Staff believes the Company's forecast reflects reasonable future conditions, and recommends the Commission accept the new forecasted PCA rate of $.003422 per kWh.

Table 2: PCA Forecast by Accounts

FERC Account	Base NPSE	Forecast	Difference	$/kWh
95% Sharing Accounts				
Account 501, Coal	$ 108,503,180	$ 112,127,106	$ 3,623,926	$ 0.00024
Account 536, Water for Power	$ 2,380,597	$ -	$ (2,380,597)	$ (0.00015)
Account 547, Other Fuel	$ 33,367,563	$ 39,202,822	$ 5,835,259	$ 0.00038
Account 555, Purchased Non-PURPA	$ 62,606,593	$ 54,988,467	$ (7,618,126)	$ (0.00049)
Account 565, 3rd Party Transmission	$ 5,455,955	$ 5,999,412	$ 543,457	$ 0.00004
Account 447, Surplus Sales	$ (51,735,153)	$ (20,930,147)	$ 30,805,006	$ 0.00200
95% Sharing Accounts Total	$ 160,578,735		$ 30,808,925	$ 0.001998
100% Sharing Accounts				
Account 555, PURPA	$ 133,853,869	$ 158,758,382	$ 24,904,513	$ 0.00170
Account 555, DR Incentives	$ 11,252,265	$ 7,401,698	$ (3,850,567)	$ (0.00028)
Total	$ 305,684,869	$ 357,547,740	$ 51,862,871	$ 0.00342

The $51,862,871 difference between base NPSE and the forecast is the system revenue requirement that forms the basis for the forecast portion of the overall PCA rate. When divided by projected sales over the next PCA year, it results in a 0.3422 ¢/kWh rate.[1] This increase is primarily attributed to two factors: (1) a decrease in forecasted surplus sales, and (2) an increase in PURPA expenditures.

[1] The forecast rate uses two sets of forecasted sales to calculate the rate. Demand Response Incentive Payments differences are divided by forecasted Idaho jurisdictional firm sales, while the PURPA and Non-PURPA differences are divided by forecasted system firm sales.

First, the largest increase to the PCA forecast is due to a 60% loss in surplus sales revenue resulting in $30.8 million of lost revenue. The Company explains that lower-than-expected hydro-generation in the Snake River Basin and lower-than-forecasted market energy prices primarily drove the reduced sales.

Specifically, the Company states that the Snake River Basin will see forecasted water increases of nearly 350,000 acre-feet from the previous year. However the Upper Snake River Basin had reservoir levels roughly 400,000 acre-feet below historical averages when this PCA year started. Although this year's water conditions are better than last year's, the reservoir system will still be 50,000 acre-feet short of filling. The result is no flood control releases, and therefore reduced surplus sales. Further, the Company indicates that lower market purchase prices result in a forecasted 31% reduction in surplus sales volume. The average market energy sale price for this year's PCA forecast is $18.43 per MWh, compared to last year's forecast of $23.65; a reduction of 22%. *See* Larkin DI, at 13. Staff calculates that a 31% reduction in sales volume, together with a 22% reduction in sales price, puts the forecast of surplus sales at $30.8 million below base NPSE. Staff notes that any changes to the forecast will be trued-up in the following year.

Second, the Company states that 370 MW of PURPA capacity is forecasted to be added to the Company's system during the PCA year at a cost of $10 million. Staff asked the Company to provide an update of installed capacity for each project, the scheduled on-line date for each project, and the current construction status for each project. The Company's response indicated that only one of the 15 solar projects contributing to the 320 MW of additional capacity is near completion. Staff notes that although this 40 MW project is nearly complete, it is nevertheless behind schedule by at least four months. Staff believes it is unlikely that all 370 MW of capacity will be added this PCA year. Nevertheless, as previously noted, any over or under-collection in the PCA will be trued-up in the following year. Staff thus believes it is acceptable to include all forecasted PURPA Account 555 expenses in the PCA forecast. Staff will continue to assess the monthly PCA Deferral Reports along with the monthly Cogeneration and Small Power Production Reports to evaluate those solar projects that come on-line during the PCA year. Any changes to the forecasted PURPA contracts will be trued-up in the following PCA.

b. The True-Up

The Company's PCA true-up primarily reflects the difference between NPSE collected through base rates and actual NPSE incurred during the deferral period of April 1, 2015 through March 31, 2016. The ending balance also includes collections through the current forecast PCA rate and monthly accrued interest. Table 3, below, summarizes the $43,661,193 true-up amount that forms the Company's proposed true-up revenue requirement for Idaho. When divided by Idaho jurisdictional forecasted sales, it determines the proposed 0.3129 ¢/kWh true-up rate.

Staff's review of the true-up included: (1) an extensive on-site audit of the various components included in the true-up or deferral balance; (2) an analysis of the methods and basis used to calculate the cost deferrals, account balances, and rates; and (3) a review of actual NPSE including monthly Risk Management Committee minutes, operating plans, and other reports that were presented to the Risk Management Committee. As a result of its review, Staff believes the Company's proposed true-up amount and resulting rate are accurate. The methods used conform to past Commission orders and actual costs incurred are reasonable and prudent.

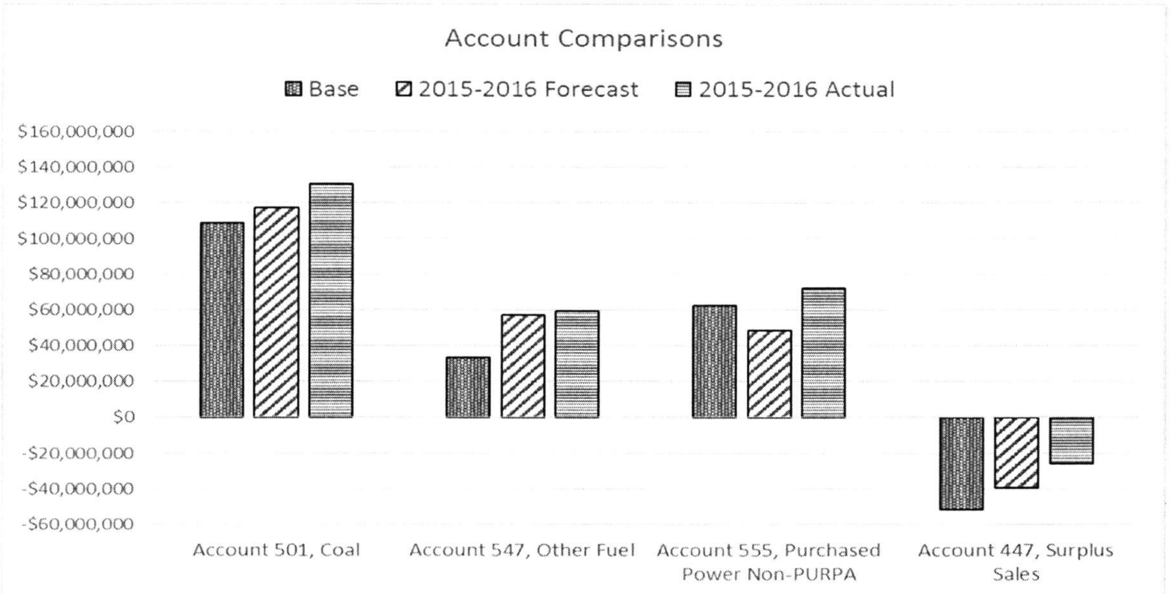
Table 3: PCA True-Up Summary

Net Power Supply Expense Differential		
Water Leases	$	78,054
Fuel Expense - Coal		22,276,812
Fuel Expense - Gas		25,993,154
Surplus Power Sales		25,675,402
Power Purchases		9,577,674
Third Party Transmission Expense		779,433
Subtotal		84,380,529
Renewable Energy Credit (REC) Sales		(1,630,681)
Subtotal		82,749,848
Amount After Jurisdictional Allocation and Sharing		75,680,834
Sales Based Adjustment		(2,955,155)
Qualifying PURPA Facilities - After Jurisdictional Allocation		10,238,596
Demand Response Incentive Payments		(4,551,152)
Total Expense Items		78,413,123
Revenue from PCA Forecast		35,020,073
Deferral Balance (Expense Items less PCA Forecast Revenue)		43,393,050
Interest on the Deferral Balance		268,143
Total Deferral	$	43,661,193

Details of the different components in the PCA true-up, as shown in Table 3, are described below.

i. Net Power Supply Expense Differential

The Company's NPSE primarily consist of costs related to coal and other fuels, non-PURPA purchased power, and surplus sales. Within the 2015/2016 PCA year, reduced availability of hydro generation required the Company to increase power generation from coal and other fuels, and to increase purchases from non-PURPA sources. Further, surplus sales declined as a result of reduced hydro generation, as well as lower overall market prices. Staff believes the Company prudently incurred NPSE to meet customer load. The following graph shows the differences between the base amount, the 2015/2016 PCA forecast, and the actual expenses for each of these contributors.



The main NPSE components are describe below.

a. *Water Leases.* The Company may lease water to produce hydro power. The Company includes the increase or decrease in water lease expense from base rates in the PCA for recovery from or credit to customers. This year's PCA deferral balance includes actual water lease expenses of $2,458,651, which is more than the $2,380,597 of lease expenses included in base rates. The deferral balance includes the difference of $78,054. This increase in water lease expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

b. *Fuel Expense - Coal*. Some of the Company's electricity comes from coal plants. The Company owns an interest in three coal plants: Bridger, Valmy and Boardman. The Company includes the increase or decrease in coal expense from base rates in the PCA for recovery from or credit to customers. From April 2015 through March 2016, the total coal expense for the three plants was $130,779,992. The total coal expense included in base rates is $108,503,180. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $22,276,812. This increase in coal costs from base costs is a cost to customers and is subject to jurisdictional allocation and sharing.

c. *Fuel Expense - Gas*. The Company owns and operates gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (3 Danskin units), Bennett Mountain, and Langley Gulch. Staff reviewed the natural gas purchases in conjunction with the Company's Operation Plan. The transactions appear reasonable and follow the Risk Management Committee's recommendations.

From April 2015 through March 2016, the total variable gas and gas transportation expense for all the gas plants was $59,360,717. The total gas and gas transportation expense included in base rates is $33,367,563. The PCA includes this increase in gas expense from base rates. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $25,993,154. This increase in natural gas expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

d. *Power Sales and Purchases*. Staff reviewed the Company's power sales and purchases in conjunction with the Company's Operating Plan. The transactions appear reasonable and follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners on a timely basis. The Power Sales and Purchases are separately discussed below.

(1.) *Power Sales.* During the PCA year ending March 31, 2016, the Company sold off-system surplus power totaling $26,059,751. The total surplus sales included in base rates is $51,735,153. The PCA includes this decrease in the power sales from base rates. Actual surplus sales were less than base amounts by $25,675,402. This revenue decrease is a cost to customers and is subject to jurisdictional allocation and sharing.

The Company indicates that during the 2015/2016 PCA year, it sold 1.23 million MWh of surplus energy into the market at an average price of $21.26 per MWh. During this same period, the average off-peak Mid-C price for electrical energy was $20.25 per MWh, while the average peak price was $25.08 per MWh. This pricing comparison indicates the Company prudently sold surplus power into the open market. For the 2016/2017 PCA year, the Company forecasts surplus sales of $1.14 million MWh at an average sales price of $18.43 per MWh.

(2.) *Power Purchases.* Excluding PURPA purchases during the PCA year ending March 31, 2016, the Company bought $72,184,267 of power on the market. The power purchases included the output from the Neal Hot Springs Power Purchase Agreement, with a 25-year levelized contract price of approximately $117.56/MWh; and the Elkhorn (Telocaset Wind Power Partners, LLC) Power Purchase Agreement, with a 20-year levelized contract price of approximately $62.38/MWh. Base rates included $62,606,593 in non-PURPA power purchases. Actual non-PURPA power purchases exceeded base amounts by $9,577,674. This increase in purchases is a cost to customers and is subject to jurisdictional allocation and sharing.

The Company purchases non-PURPA power in the wholesale market, as well as through long-term purchase contracts and exchange agreements. The average purchase price during the 2015/2016 PCA year was $49.47 per MWh.

This price factors in the cost of third-party transmission. Although this price is greater than the average Mid-C peak price of $25.08 per MWh, the difference occurs because some of the Company's existing purchase agreements require it to buy power for more than the Mid-C peak price, which skews the average cost of purchased power. These agreements are in place with Telocaset Wind Power Partners, LLC, USG Oregon LLC, Clatskanie People's Utility, and Raft River Energy I, LLC.

e. *Third-Party Transmission*. In Order No. 30715, the Commission directed the Company to track third-party transmission costs associated with market purchases and off-system sales through the PCA like other variable power supply costs. Including transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales. For the April 2015 through March 2016 PCA period, the actual third-party transmission expense is $6,235,388. The third-party transmission expense included in base rates is $5,455,955. This year's PCA deferral balance includes the difference between actual costs and base costs of $779,433. Because the actual costs are more than the amount included in base rates, this amount represents a cost to customers. This cost to customers is subject to jurisdictional allocation and sharing.

ii. Renewable Energy Credit Sales.

In Order No. 30818, the Commission ordered that revenues from the sale of renewable energy credits ("RECs") should benefit customers. The deferral balance includes $1,630,681 in revenue from REC sales. After allocation and sharing, Idaho ratepayers receive $1,478,144 from renewable energy credit sales. This increase in revenues benefits customers and is subject to jurisdictional allocation and sharing.

iii. Emission Allowance Sales.

In Order No. 32424, the Commission ordered that revenues from the sale of emission allowances, plus any applicable interest, be reflected in the PCA and used to benefit customers by reducing the Company's PCA deferral balance. In the current PCA period, there were no emission allowance sales.

iv. Sales-Based Adjustment ("SBA").

The Company proposed a $2,955,155 SBA (credit to customers) from the Company's over-recovery of actual NPSE collected through base rates due to differences in base versus actual sales. This is the first year that the SBA has fully replaced the Load Change Adjustment ("LCA") used in previous PCAs. *See* Order No. 33307 (noting that the SBA will eliminate the line loss bias inherent with using loads at generation in the LCA).

The SBA uses the $26.72/MWh SBA rate established in Order No. 33307 (Case No. IPC-E-15-15), representing NPSE[2] embedded in base rates during the 2015-2016 deferral period. When multiplied by the difference in actual and base rate sales, it calculates the over or under recovery of actual NPSE due to sales that are higher or lower, respectively, than normalized base rate sales (subject to 95% customer sharing). During the 2015-2016 deferral period, actual sales were $116,418 higher than sales used to set base rates, resulting in a credit back to customers.

Staff audited and analyzed the Company's SBA calculations by: (1) auditing actual sales; (2) confirming the SBA rate and sales used to set base rates; and (3) verifying the Company's method for calculating the SBA was consistent with the Commission's prior orders. Staff believes the Company calculated the SBA adjustment consistently with past Commission orders, and that the adjustment is reasonably accurate in calculating over-recovery of NPSE due to increased sales.

v. Qualifying Facility/PURPA Expense.

For the April 2015 through March 2016 PCA period, the actual Idaho Jurisdictional PURPA expense is $137,399,772. The Idaho Jurisdictional PURPA expense included in base rates is $127,161,176. The difference between actual PURPA expense and base PURPA expense is included in the PCA for recovery from

[2] For purposes of the SBA rate, as was the case for the load change adjustment rate (LCAR), NPSE is the energy-related production cost embedded in base rates. Base energy-related production cost is used to determine the numerator of the $/MWh rate in establishing these rates. *See* Order No. 32206 (GNR-E-10-03).

or credit to customers. In this year's PCA deferral balance, the actual Idaho jurisdictional PURPA expense exceeded the PURPA expense included in base rates by $10,238,596. This amount is a cost to customers and increases the PCA deferral balance. PURPA contracts are not subject to sharing, but they are subject to jurisdictional allocation.

vi. Demand Response Incentive Payments.

On December 30, 2011, Commission Order No. 32426 found the Company's NPSE to be $208,100,936, which included $11,252,265 of Demand Response (DR) Incentive payments. Staff has reviewed the $11,252,265 of DR payments included in the Company's Base NPSE, and confirms that this figure is correct.

The Company forecasts DR Incentive expenses of $7,401,698 for the 2016-2017 PCA Year, which is $3,850,567 less than the $11,252,265 included in the Base NPSE. *See* Larkin DI, Table 1. Staff has reviewed the forecasted DR Incentive expenses and believes they are reasonable. Further, Staff has confirmed that the Company has correctly removed $3,850,567 from the 2016-2017 PCA forecast, which reduces the PCA forecast by 0.0276 cents/kWh. *See* Larkin DI, Table 4.

Staff also audited the Company's proposed DR Incentive Payment Deferral balance. Staff confirms there were $6,701,113 in actual DR Incentive expenditures in the 2015-2016 PCA Year, which is $4,551,152 less than the $11,252,265 included in the Base NPSE. Staff further confirms Company's proposed PCA true-up balance correctly omits this amount. Staff therefore believes all computations related to DR Incentives have been accounted for properly.

c. The Reconciliation of the True-up

The reconciliation of the true-up amount is the difference between what was approved to be collected or refunded when the PCA rate for last year's true-up was set, and what was actually collected or refunded. The reconciliation of the true-up assures that the amount approved for recovery is the amount actually recovered. Table 4, below, summarizes the reconciliation of the true-up for the 2015-2016 PCA period. The $5,073,137 ending balance amount is the revenue requirement used to form the reconciliation of the true-up portion of the overall PCA rate. When divided by forecasted Idaho jurisdictional sales, the calculated result is a negative 0.0364 ¢/kWh or a rate credit. Staff believes the rate reasonably reflects the amount to be credited to customers over next year's PCA collection period.

Staff audited the amounts booked to the reconciliation of the true-up, verified the Company's calculations, and reviewed the method used to ensure it complies with past Commission orders. As a result of its review, Staff believes the Company correctly reconciled the true-up.

Table 4: True-Up Reconciliation

2014-2015 Forecast True-Up	**34,515,981**
2014-2015 True-Up of the True-Up Balance	**1,484,515**
Revenue Sharing (Order No. 33306 + interest)	**(8,029,177)**
DSM Rider Funds (Order No. 33306)	**(3,970,036)**
LCA to SBA Adjustment (Order No. 33307)	**(1,470,798)**
Salmon MWh Adjustment	**(839)**
Net Amount Set for Recovery/(Refund)	**22,529,647**
Collections from True-Up Rates	**(27,688,442)**
Interest	**85,657**
Subtotal	**(27,602,785)**
True-Up Reconciliation	**(5,073,137)**

The specifics of Staff's review are discussed below.

i. <u>2014-2015 Forecast True-up Balance.</u>

The ending true-up deferral balance from the April 2014 through March 2015 PCA period was approved in Order No. 33306; Case No. IPC-E-15-14. The ending deferral balance in last year's PCA was $34,515,981. This amount is added to the beginning balance of the reconciliation of the true-up, with recovery set to start in June 2015 when the PCA rates changed. This amount has been properly recorded in the month of April 2015 in the reconciliation of the true-up for recovery.

ii. <u>2014-2015 Reconciliation of the True-Up Balance</u>

The remaining balance in the reconciliation of the true-up that was under-recovered in the previous PCA period is the beginning balance of the reconciliation of the true-up for this PCA period. The amount of $1,484,515 was not recovered in the previous period, and has been properly recorded in the reconciliation of the true-up as the beginning balance.

iii. Revenue Sharing.

The Revenue Sharing benefit of $8,029,177 was approved in the previous PCA, Order No. 33306, Case No. IPC-E-15-14. Staff has verified that this Revenue Sharing amount is properly reflected in the reconciliation of the true-up.

iv. DSM Rider Funds.

The DSM Rider Transfer was approved in Order No. 33000 and current DSM rider rates approved in Order No. 33306. The $3,970,036 amount on Line 104 of Company Exhibit No. 1 represents the collections of the DSM rider portion of current Schedule 55 rates over the 2015-2016 PCA period. Staff has verified that the reconciliation of the true-up properly reflects this amount.

v. LCA to SBA Adjustment.

The Company included a $1,470,798 one-time adjustment (credit to customers) in the reconciliation of the true-up as a result of a Settlement Agreement in which the parties agreed to change the true-up's LCA to an SBA beginning on January 1, 2015. *See* Order Nos. 33306 and 33307. Because it was too late to include the methodology change in the true-up of the 2015-2016 PCA, the Company has included the credit in this year's reconciliation of the true-up. Staff believes the adjustment complies with the Commission's orders.

vi. Salmon MWh Adjustment.

The Salmon MWh Adjustment reflects revised generation in the LCAR expense adjustment. The Salmon MWh Adjustment totals $839 and benefits customers. The Company provided Staff with confidential workpapers supporting this adjustment. Staff has verified the calculations and agrees with this adjustment.

2. Additional PCA Components

a. DSM Rider Adjustment and Transfer

On March 21, 2014, the Company increased its base level NPSE by $99.3 million. *See* Order No. 33000. This increase causes the Company to collect an extra $3.97 million per year in DSM Rider funds revenue. Therefore, the Company was to implement the change to base level NPSE so the change would have no net impact to the overall DSM Rider revenue collected through customer rates. *Id.* To maintain "revenue neutrality," the Company implemented a DSM Rider Ongoing Transfer that removes $3.97 million from the DSM Rider balancing account, and applies that amount to directly reduce the PCA. Staff has reviewed the treatment of the DSM Rider Ongoing Transfer and confirms it has been accounted for correctly. The result is a rate of negative 0.0284 ¢/kWh included in Schedule 55 rates. Staff believes the Company should continue to include this adjustment in PCA rate calculations until the level of NPSE recovered in base rates is re-established in a general rate case, or adjusted by Commission order.

b. Revenue Sharing

In 2010, the Commission established a mechanism that required the Company to share revenue if the Company's actual Idaho jurisdictional year-end ROE exceeded 10.5% in the years 2009 through 2011. If Revenue Sharing was triggered, the Company was to share 50% of any earnings above 10.5% ROE with customers. *See* Order No. 30978. For the years ending December 31, 2009 and 2010, Revenue Sharing was not triggered, as the Idaho jurisdictional year-end ROE was between 9.5% and 10.5%. Revenue Sharing was triggered for the years ending December 31, 2011 and 2012.

The Commission subsequently modified the Revenue-Sharing mechanism and extended it through 2014. The Commission also reduced the sharing trigger to 10%, with equal sharing between customers and the Company when the ROE is greater than 10% up to and including 10.5%. This customer portion of the "Revenue Sharing" benefit serves as a customer credit that is netted with the traditional PCA components to yield a combined rate that is set forth in Schedule 55. In addition, when the ROE exceeds 10.5%, the earnings above 10.5% continue to be shared with customers receiving 75% of the earnings above 10.5%. The customer share of earnings above 10.5% were applied to the Company's pension balancing account. This Revenue-Sharing contribution to the pension balancing account reduced the amount the Company would otherwise be allowed to collect from customers. *See* Order No. 32424.

In Case No. IPC-E-14-14, the Commission extended the terms of the December 2011 Idaho Settlement Stipulation, with modification, for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by Commission Order or the full $45 million of additional Accumulated Deferred Investment Tax Credits ("ADITC") contemplated by the Settlement Stipulation has been amortized. *See* Order No. 33149. The provisions of the new Settlement Stipulation were applied for calendar year 2015 and are reflected in the current PCA case.

The provisions of the current Revenue Sharing mechanism are:

- The Company's annual Idaho ROE in any year is less than 9.5%, then the Company may amortize up to $25 million of additional ADITC to help achieve a 9.5% Idaho ROE for that year, and may amortize up to a total of $45 million of additional ADITC over the 2015 through 2019 period.
- If the Company's annual Idaho ROE in any year exceeds 10.0%, the amount of earnings exceeding a 10.0% Idaho ROE and up to and including a 10.5% Idaho ROE will be allocated 75% to the Company's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA and 25% to the Company.
- If the Company's annual Idaho ROE in any year exceeds 10.5%, the amount of earnings exceeding a 10.5% Idaho ROE will be allocated 50% to the Company's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment, 25% to the Company's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 25% to the Company.
- If the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized the sharing provisions would terminate.
- In the event the IPUC approves a change to the Company's Idaho-jurisdictional allowed return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2020, the Idaho ROE thresholds (9.5%, 10.0%, and 10.5%) will be adjusted prospectively. *See id.*

For 2015, the Company's jurisdictional ROE was 10.13%. The amount of the Company's earnings exceeding the ROE of 10% is $2,565,553. Per the terms of the stipulation, 75% is shared with customers as a direct reduction to PCA rates, effective June 1, 2016. The customer amount is $1,924,165 and, after tax gross-up, the Revenue Sharing amount to be flowed through to customers through the PCA is $3,159,478. *See* Attachment B, column A.

Staff has reviewed the workpapers, source documents and supporting documentation for the Revenue Sharing calculations and agrees with the Company's filing.

B. Rate Calculations

As noted previously, this year's Schedule 55 rates consist of the traditional PCA components (forecast rate, true-up rate, and reconciliation of the true-up rate), the DSM Rider, and Revenue Sharing rates. Attachment B to these comments breaks down the different components by rate class. Staff thoroughly reviewed all rate calculations and confirmed they are accurate and comply with past Commission orders. Staff also verified that the basis for the billing determinants used remains reasonable.

When added together, the three traditional components form the overall PCA rate of 0.6187¢/kWh. *See* Attachment B, column E. The components have traditionally been calculated on an equal cents per kilowatt-hour basis to ensure customers share in the credit or surcharge based on the amount of energy consumed. Staff finds no reason to deviate from past practices.

The Company proposes to credit the roughly $4 million DSM Rider benefit to customers through a rate of 0.0284 ¢/kWh on an equal cents per kilowatt-hour basis. *See* Attachment B, column D. This complies with past Commission orders, and Staff believes the rationale for allowing each customer class to receive credit in the same proportion as established in base rates remains valid.

The Revenue Sharing credit is allocated based on each class's proportional share of forecasted base rate revenues for the collection period of June 1, 2016 through May 31, 2017. This has been used in previous PCA cases to ensure each class's contribution to the credit is reimbursed in roughly the same way. The allocations are then distributed in rates on a ¢/kWh basis for all customer classes except special contract customers. The special contract customers will receive their benefit through a flat dollar per month credit in 12 equal proportions. *See* Attachment B, column C. Staff believes this method remains valid and finds no reason to deviate from past practices.

III. CUSTOMER RELATIONS

The Company filed copies of its press release and customer notice with its Application. Staff reviewed the documents and determined that both satisfy Commission Rule of Procedure 125, IDAPA 31.01.01.125.

The notice was included with bills mailed to customers beginning April 22, 2016. The last notice will be mailed on May 20, 2016, which will allow most but not all customers a reasonable opportunity to file timely comments with the Commission by the May 19, 2016 deadline. Starting March 15, the Company began providing information on its website about its intent to make its annual PCA filing. After its Application was filed, the website included a direct link to the Company's PCA press release and customer notice. As of May 19, 2016, the Commission had received four comments from customers. Each customer opposes the proposed increase.

IV. STAFF RECOMMENDATIONS

Staff recommends that the Commission approve a total deferral amount of $43,393,050 ($78,413,123 without 2015-2016 forecast collections) for recovery through Schedule 55 rates as shown in Staff Attachment B, effective June 1, 2016. Staff further recommends the following:

1. The Commission approve Revenue Sharing amounts proposed by the Company; specifically PCA revenue sharing of $3,159,478.
2. The Commission approve DSM Rider Transfer Funds of $3,970,036 to be credited to customers as a reduction.
3. The Commission approve Schedule 55 rates as filed in Attachment 1 to the Company's Application.
4. The Company include all attachments and exhibits including any supporting workpapers in electronic format with all formula intact in the filing of future PCA cases.

Respectfully submitted this 19th day of May 2016.

For: Brandon Karpen
Deputy Attorney General

Technical Staff: Mike Louis
Rick Keller
Kathy Stockton
Patricia Harms
Mark Rogers
Daniel Klein

i:umisc/comments/ipce16.8bkmlrkklsphmrdk comments

Power Cost Adjustment
April 2015 thru March 2016

	Prior	New (Effective 6/1/15)		April	May	June	July	August	September	October	November	December	January	February	March	Totals
PCA Forecasted Revenues																
Actual Idaho Jurisdictional Billing Month Sales			Mwh	961,156	1,061,961	1,147,790	1,557,565	1,379,371	1,342,005	1,012,234	936,904	1,069,144	1,155,022	1,050,660	941,498	13,615,310
% of Prior Period Billings at Old Rate				100.000%	100.000%	58.009%	0.003%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	100.000%	0.000%	
% of Current Period Billings at New Rate				0.000%	0.000%	41.990%	99.997%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	0.000%	100.000%	
Forecasted Billing Month Revenues	$ 1.609	$ 2.815	$	(1,546,499.59)	(1,708,694.80)	(2,368,621.22)	(4,379,809.97)	(3,882,928.81)	(3,777,743.67)	(2,849,438.40)	(2,637,385.19)	(3,009,639.15)	(3,251,387.22)	(2,957,609.06)	(2,650,315.96)	(35,020,073.04)
Sales Based Adjustment	Prior	New (Effective 6/1/14)														
Actual Idaho Jurisdictional Billing Month Sales			Mwh	961,156	1,061,961	1,147,790	1,557,565	1,379,371	1,342,005	1,012,234	936,904	1,069,144	1,155,022	1,050,660	941,498	13,615,310
Normalized Idaho Jurisdictional Billing Month Sales			Mwh	947,192	953,286	1,131,686	1,370,142	1,428,766	1,300,608	1,045,495	957,864	1,081,014	1,177,663	1,101,149	1,004,027	13,498,892
Sales Change			Mwh	13,964	108,675	16,104	187,423	(49,395)	41,397	(33,261)	(20,960)	(11,870)	(22,641)	(50,489)	(62,529)	116,418
% of Prior Period Billings at Old Rate				0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
% of Current Period Billings at New Rate				100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
Sales Adjustment Prior To Sharing		$ 26.72	$	(373,118.08)	(2,903,796.00)	(430,298.88)	(5,007,942.56)	1,319,834.40	(1,106,127.84)	888,733.92	560,051.20	317,166.40	604,967.52	1,349,066.08	1,670,774.88	(3,110,688.96)
Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Sales Based Adjustment			$	(354,462.18)	(2,758,606.20)	(408,783.94)	(4,757,545.43)	1,253,842.68	(1,050,821.45)	844,297.22	532,048.64	301,308.08	574,719.14	1,281,612.78	1,587,236.14	(2,955,154.52)
Actual Non-QF																
Fuel Expense-Coal			$	10,719,507.16	8,148,495.82	14,745,927.44	14,898,475.11	18,065,415.27	10,904,730.72	9,622,839.62	9,589,670.63	10,419,660.84	10,581,123.02	8,513,914.83	4,570,231.44	130,779,991.90
Fuel Expense-Gas			$	2,071,160.49	4,340,495.49	6,310,174.96	7,735,567.10	8,941,254.00	5,746,499.93	3,749,765.01	3,104,906.18	5,390,361.88	5,024,228.65	3,968,136.99	2,978,166.36	59,360,717.04
Non-Firm Purchases			$	4,046,263.01	2,863,240.66	10,099,422.39	9,356,606.10	7,883,392.52	4,467,697.61	5,570,061.34	8,105,597.99	8,034,132.40	4,314,882.64	3,797,971.69	3,644,998.50	72,184,266.85
Third Party Transmission			$	389,701.25	319,651.21	599,152.22	1,285,851.01	828,124.04	603,419.48	529,302.95	609,272.15	157,869.28	310,482.04	318,865.00	283,697.04	6,235,387.67
Surplus Sales			$	(1,059,360.10)	(1,505,677.05)	(1,039,300.58)	(3,087,225.97)	(974,119.53)	(2,079,282.99)	(3,510,785.98)	(1,454,310.05)	(2,319,464.24)	(3,827,618.00)	(2,424,594.16)	(2,778,012.63)	(26,059,751.28)
Water for Power (Leases)			$	34,000.00	-	343,499.00	1,474,843.20	606,309.00	-	-	-	-	-	-	-	2,458,651.20
Total Actual Non-QF			$	16,201,271.81	14,166,206.13	31,058,875.43	31,664,116.55	35,350,375.30	19,643,064.75	15,961,182.94	19,955,136.90	21,682,560.16	16,403,098.35	14,174,294.35	8,699,080.71	244,959,263.38
Idaho Allocation				95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
Net Idaho Jurisdictional Actual Non-QF			$	15,423,610.76	13,514,560.65	29,692,284.91	30,302,559.54	33,794,958.79	18,798,412.97	15,242,929.71	18,917,469.78	20,641,797.27	15,582,943.43	13,550,625.40	8,307,622.08	233,769,775.29
Base Non-QF																
Fuel Expense-Coal			$	7,525,242.00	7,487,643.00	9,019,153.00	11,385,255.00	12,185,412.00	10,796,845.00	7,781,442.00	7,302,324.00	8,455,019.00	9,553,773.00	8,912,994.00	8,098,078.00	108,503,180.00
Fuel Expense-Gas			$	2,314,209.00	2,302,646.00	2,773,625.00	3,501,263.00	3,747,333.00	3,320,312.00	2,392,997.00	2,245,656.00	2,600,139.00	2,938,035.00	2,740,979.00	2,490,369.00	33,367,563.00
Non-Firm Purchases			$	4,342,083.00	4,320,388.00	5,204,073.00	6,569,319.00	7,031,012.00	6,229,805.00	4,489,910.00	4,213,459.00	4,878,566.00	5,512,549.00	5,142,819.00	4,672,610.00	62,606,593.00
Third Party Transmission			$	378,398.00	376,507.00	453,517.00	572,494.00	612,729.00	542,907.00	391,281.00	367,189.00	425,151.00	480,400.00	448,179.00	407,203.00	5,455,955.00
Surplus Sales			$	(3,588,093.00)	(3,570,166.00)	(4,300,402.00)	(5,428,577.00)	(5,810,099.00)	(5,148,019.00)	(3,710,251.00)	(3,481,805.00)	(4,031,418.00)	(4,555,312.00)	(4,249,784.00)	(3,861,227.00)	(51,735,153.00)
Water for Power (Leases)			$	165,106.00	164,281.00	197,883.00	249,796.00	267,352.00	236,886.00	170,727.00	160,216.00	185,506.00	209,613.00	195,555.00	177,676.00	2,380,597.00
Net 95% Items			$	11,136,945.00	11,081,299.00	13,347,849.00	16,849,550.00	18,033,739.00	15,978,736.00	11,516,106.00	10,807,039.00	12,512,963.00	14,139,058.00	13,190,742.00	11,984,709.00	160,578,735.00
Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Net Idaho Jurisdiction 95% Items			$	10,580,097.75	10,527,234.05	12,680,456.55	16,007,072.50	17,132,052.05	15,179,799.20	10,940,300.70	10,266,687.05	11,887,314.85	13,432,105.10	12,531,204.90	11,385,473.55	152,549,798.25
Idaho Jurisdiction Change From Base			$	4,843,513.01	2,987,326.60	17,011,828.36	14,295,487.04	16,662,906.74	3,618,613.77	4,302,629.01	8,650,782.73	8,754,482.42	2,150,838.33	1,019,420.50	(3,077,851.47)	81,219,977.04
Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Net Power Supply Costs Deferral			$	4,601,337.36	2,837,960.27	16,161,236.94	13,580,712.69	15,829,761.40	3,437,683.08	4,087,497.56	8,218,243.59	8,316,758.30	2,043,296.41	968,449.48	(2,923,958.90)	77,158,978.18
Emission Allowance and REC Sales																
Emission Allowance Sales Credit			$	-	-	-	-	-	-	-	-	-	-	-	-	0.00
Renewable Energy Credit Sales			$	(729,608.57)	(20,816.50)	324.76	(308,073.06)	676.73	(10,396.78)	(85,310.17)	(1,738.78)	(58,413.88)	347.14	(400,227.23)	(17,444.40)	(1,630,680.74)
Total Emission Allowances and REC Sales			$	(729,608.57)	(20,816.50)	324.76	(308,073.06)	676.73	(10,396.78)	(85,310.17)	(1,738.78)	(58,413.88)	347.14	(400,227.23)	(17,444.40)	(1,630,680.74)
Idaho Allocation				95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Net Emission Allowances and REC Sales			$	(659,857.99)	(18,865.99)	294.95	(280,084.62)	614.61	(9,452.23)	(77,397.65)	(1,565.95)	(52,829.51)	313.29	(363,486.37)	(15,826.43)	(1,478,143.89)
Demand Response Incentive Payments																
Actual			$	135.69	623.98	261.81	2,683,791.39	3,107,377.87	1,049,704.59	(144,707.89)	3,925.47	-	-	-	-	6,701,112.91
Base			$	780,401.00	776,502.00	935,327.00	1,180,702.00	1,263,682.00	1,119,681.00	806,970.00	757,284.00	876,823.00	990,769.00	924,317.00	839,807.00	11,252,265.00
Change From Base			$	(780,265.31)	(775,878.02)	(935,065.19)	1,503,089.39	1,843,695.87	(69,976.41)	(951,677.89)	(753,358.53)	(876,823.00)	(990,769.00)	(924,317.00)	(839,807.00)	(4,551,152.09)
Idaho Allocation				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Sharing Percentage				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Demand Response Incentive Payment Deferral			$	(780,265.31)	(775,878.02)	(935,065.19)	1,503,089.39	1,843,695.87	(69,976.41)	(951,677.89)	(753,358.53)	(876,823.00)	(990,769.00)	(924,317.00)	(839,807.00)	(4,551,152.09)
Actual QF																
Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)			$	10,851,939.60	9,025,249.06	12,763,083.30	15,842,792.65	13,255,084.60	9,444,845.88	9,260,244.12	13,829,108.00	14,324,978.01	13,304,555.08	11,725,516.55	10,413,792.31	144,041,189.16
Idaho Allocation				95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
Idaho Jurisdictional Actual QF			$	10,331,046.50	8,610,087.60	12,201,507.63	15,161,552.57	12,671,860.88	9,038,717.51	8,843,533.13	13,109,994.38	13,637,379.07	12,639,327.33	11,209,593.82	9,945,171.66	137,399,772.08
Base QF			$	9,283,440.00	9,237,057.00	11,126,388.00	14,045,307.00	15,032,413.00	13,319,420.00	9,599,498.00	9,008,440.00	10,430,450.00	11,785,917.00	10,995,427.00	9,990,113.00	133,853,870.00
Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Idaho Jurisdictional Base			$	8,819,268.00	8,775,204.15	10,570,068.60	13,343,041.65	14,280,792.35	12,653,449.00	9,119,523.10	8,558,018.00	9,908,927.50	11,196,621.15	10,445,655.65	9,490,607.35	127,161,176.50
Idaho Jurisdiction Change From Base			$	1,511,778.50	(165,116.55)	1,631,439.03	1,818,510.92	(1,608,931.47)	(3,614,731.49)	(275,989.97)	4,551,976.38	3,728,451.57	1,442,706.18	763,938.17	454,564.31	10,238,595.58
Sharing Percentage				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
QF Deferral			$	1,511,778.50	(165,116.55)	1,631,439.03	1,818,510.92	(1,608,931.47)	(3,614,731.49)	(275,989.97)	4,551,976.38	3,728,451.57	1,442,706.18	763,938.17	454,564.31	10,238,595.58
Total Deferral			$	2,772,030.79	(2,589,201.29)	14,080,500.57	7,484,872.98	13,436,054.28	(5,085,042.17)	777,290.87	9,909,958.94	8,407,226.29	(181,121.20)	(1,231,412.00)	(4,388,107.84)	43,393,050.22

True-Up Summary:

Principal Balances														
Beginning True-Up Balance	$	0.00	2,772,030.79	182,829.50	14,263,330.07	21,748,203.05	35,184,257.33	30,099,215.16	30,876,506.03	40,786,464.97	49,193,691.26	49,012,570.06	47,781,158.06	-
Amount Deferred	$	2,772,030.79	(2,589,201.29)	14,080,500.57	7,484,872.98	13,436,054.28	(5,085,042.17)	777,290.87	9,909,958.94	8,407,226.29	(181,121.20)	(1,231,412.00)	(4,388,107.84)	43,393,050.22
Ending Balance	$	2,772,030.79	182,829.50	14,263,330.07	21,748,203.05	35,184,257.33	30,099,215.16	30,876,506.03	40,786,464.97	49,193,691.26	49,012,570.06	47,781,158.06	43,393,050.22	43,393,050.22
Interest Balances														
Accrual thru Prior Month	$	-	-	2,309.10	2,461.40	14,342.75	32,459.00	61,767.49	86,840.14	112,560.27	146,535.40	187,513.74	228,341.21	
Monthly Interest Rate (Annual 1%)		0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	
Monthly Interest Inc/(Exp)	$	0.00	2,309.10	152.30	11,881.35	18,116.25	29,308.49	25,072.65	25,720.13	33,975.13	40,978.34	40,827.47	39,801.70	268,142.91
Interest Accrued to date	$	-	2,309.10	2,461.40	14,342.75	32,459.00	61,767.49	86,840.14	112,560.27	146,535.40	187,513.74	228,341.21	268,142.91	268,142.91
Ending True-Up Balance	$	2,772,030.79	185,138.60	14,265,791.47	21,762,545.80	35,216,716.33	30,160,982.65	30,963,346.17	40,899,025.24	49,340,226.66	49,200,083.80	48,009,499.27	43,661,193.13	43,661,193.13

True-Up of the True-Up Summary:

Beginning Balance True-Up of True-Up	$	1,484,514.90	32,494,113.20	15,121,597.51	11,816,306.88	9,294,636.96	7,067,692.43	4,898,060.59	3,250,688.39	1,724,781.66	2,749.11	(1,848,820.27)	(3,543,398.26)	1,484,514.90
Adjustments:														-
Revenue Sharing Order No. 33306			(8,029,176.53)											(8,029,176.53)
DSM Rider Forecasted Surplus Funds Order No. 33306			(3,970,036.00)											(3,970,036.00)
2014-15 PCA trnsfr per IPUC Ord No. 33306	$	34,515,981.39												34,515,981.39
LCA to SBA additional benefit Jan - Mar 2015 Order No. 33307			(1,470,797.50)											(1,470,797.50)
Salmon MWH Adjustment			(838.95)											(838.95)
														-
True-Up of True-Up Balance	$	36,000,496.29	19,023,264.22	15,121,597.51	11,816,306.88	9,294,636.96	7,067,692.43	4,898,060.59	3,250,688.39	1,724,781.66	2,749.11	(1,848,820.27)	(3,543,398.26)	22,529,647.31
Monthly Interest Rate (Annual 1%)		0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	
Monthly Interest	$	30,000.41	15,852.72	12,596.29	9,842.98	7,742.43	5,887.39	4,080.08	2,707.82	1,436.74	2.29	(1,540.07)	(2,951.65)	85,657.43
True-Up of True-Up Including Interest	$	36,030,496.70	19,039,116.94	15,134,193.80	11,826,149.86	9,302,379.39	7,073,579.82	4,902,140.67	3,253,396.21	1,726,218.40	2,751.40	(1,850,360.34)	(3,546,349.91)	22,615,304.74
Monthly Collection Applied To Balance	$	(3,536,383.50)	(3,917,519.43)	(3,317,886.92)	(2,531,512.90)	(2,234,686.96)	(2,175,519.23)	(1,651,452.28)	(1,528,614.55)	(1,723,469.29)	(1,851,571.67)	(1,693,037.92)	(1,526,787.39)	(27,688,442.04)
Ending True-Up of the True-Up Balance	$	32,494,113.20	15,121,597.51	11,816,306.88	9,294,636.96	7,067,692.43	4,898,060.59	3,250,688.39	1,724,781.66	2,749.11	(1,848,820.27)	(3,543,398.26)	(5,073,137.30)	(5,073,137.30)

Negative amounts indicate benefit to the customer.

Idaho Billed Sales	Mwh	961,156	1,061,961	1,147,790	1,557,565	1,379,371	1,342,005	1,012,234	936,904	1,069,144	1,155,022	1,050,660	941,498	13,615,310
Oregon Billed Sales	Mwh	48,660	50,697	53,323	70,672	62,751	60,364	47,405	50,902	54,418	61,311	48,520	44,463	653,486
Total	Mwh	1,009,816	1,112,658	1,201,113	1,628,237	1,442,122	1,402,369	1,059,639	987,806	1,123,562	1,216,333	1,099,180	985,961	14,268,796
Idaho % Billed Sales		95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
Oregon % Billed Sales		4.8%	4.6%	4.4%	4.3%	4.4%	4.3%	4.5%	5.2%	4.8%	5.0%	4.4%	4.5%	

Idaho Power Company
Total PCA Rate Calculation
Class Allocated Revenue Sharing and Rider Transfer
State of Idaho
Sales Based Adjustment Rate Methodology

Line No	Tariff Description	Rate Sch. No.	(A) Allocated Revenue Sharing Benefit	(B) Allocated DSM Rider (Ongoing) Transfer	(C) Revenue Sharing Dollars per kWh Rate	(D) Allocated DSM Rider (Ongoing) Transfer Dollars per kWh Rate	(E) PCA per kWh Rate	(F) Revenue Sharing + Ongoing DSM Rider Transfer + PCA Rate
	Uniform Tariff Rates:							
1	Residential Service	1	($1,394,335)	($1,418,213)	(0.000280)	($0.000284)	$0.006187	$0.005623
2	Master Metered Mobile Home Park	3	($1,351)	($1,439)	(0.000267)	($0.000284)	$0.006187	$0.005636
3	Residential Service Energy Watch	4	$0	$0	0.000000	($0.000284)	$0.006187	$0.005903
4	Residential Service Time-of-Day	5	($6,446)	($6,811)	(0.000269)	($0.000284)	$0.006187	$0.005633
5	Small General Service	7	($46,382)	($37,167)	(0.000355)	($0.000284)	$0.006187	$0.005548
6	Large General Service - Secondary	9S	($699,887)	($948,627)	(0.000210)	($0.000284)	$0.006187	$0.005693
7	Large General Service - Primary	9P	($85,515)	($133,156)	(0.000183)	($0.000284)	$0.006187	$0.005720
8	Large General Service - Transmission	9T	($672)	($965)	(0.000198)	($0.000284)	$0.006187	$0.005704
9	Dusk to Dawn Lighting	15	($3,882)	($1,810)	(0.000610)	($0.000284)	$0.006187	$0.005292
10	Large Power Service - Secondary	19S	($1,163)	($1,823)	(0.000182)	($0.000284)	$0.006187	$0.005721
11	Large Power Service - Primary	19P	($351,677)	($621,521)	(0.000161)	($0.000284)	$0.006187	$0.005742
12	Large Power Service - Transmission	19T	($5,054)	($9,354)	(0.000154)	($0.000284)	$0.006187	$0.005749
13	Agricultural Irrigation Service	24	($426,901)	($530,569)	(0.000229)	($0.000284)	$0.006187	$0.005674
14	Unmetered General Service	40	($2,867)	($3,247)	(0.000251)	($0.000284)	$0.006187	$0.005651
15	Street Lighting	41	($10,663)	($7,798)	(0.000389)	($0.000284)	$0.006187	$0.005514
16	Traffic Control Lighting	42	($500)	($800)	(0.000178)	($0.000284)	$0.006187	$0.005725
17	Total Uniform Tariffs		($3,037,295)	($3,723,302)				
18	Special Contracts							
19	Micron	26	($68,753)	($134,649)	NA	($0.000284)	$0.006187	$0.005903
20	J R Simplot	29	($25,946)	($54,666)	NA	($0.000284)	$0.006187	$0.005903
21	DOE	30	($27,484)	($57,419)	NA	($0.000284)	$0.006187	$0.005903
23	Total Special Contracts		($122,183)	($246,734)				
24	Total Idaho Retail Sales		($3,159,478)	($3,970,036)				

Note:
(1) June 1, 2016 - May 31, 2017 Forecasted Test Year

Attachment B
Case No. IPC-E-16-08
Staff Comments
05/19/2016

Idaho Power Company
Calculation of Revenue Impact 2016 - 2017
State of Idaho
PCA
Filed April 15, 2016

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers [1]	Normalized Energy (kWh) [1]	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	429,310	4,985,427,763	$489,737,127	98.23	$6,599,939	$496,337,066	99.56	1.35%
2	Master Metered Mobile Home Park	3	22	5,059,520	$476,363	94.15	$6,590	$482,954	95.45	1.38%
3	Residential Service Energy Watch	4	0	0	$0	0.00	$0	$0	0.00	N/A
4	Residential Service Time-of-Day	5	1,335	23,944,320	$2,271,577	94.87	$31,255	$2,302,832	96.17	1.38%
5	Small General Service	7	27,894	130,654,397	$16,110,728	123.31	$187,167	$16,297,894	124.74	1.16%
6	Large General Service	9	34,643	3,806,172,174	$271,932,984	71.45	$4,602,523	$276,535,507	72.65	1.69%
7	Dusk to Dawn Lighting	15	0	6,361,595	$1,280,706	201.32	$11,707	$1,292,412	203.16	0.91%
8	Large Power Service	19	110	2,224,117,036	$126,269,727	56.77	$2,534,446	$128,804,173	57.91	2.01%
9	Agricultural Irrigation Service	24	18,225	1,865,104,107	$146,676,903	78.64	$2,312,057	$148,988,960	79.88	1.58%
10	Unmetered General Service	40	1,346	11,414,394	$979,536	85.82	$14,591	$994,128	87.09	1.49%
11	Street Lighting	41	1,674	27,412,831	$3,566,355	130.10	$41,765	$3,608,121	131.62	1.17%
12	Traffic Control Lighting	42	547	2,811,020	$174,817	62.19	$3,274	$178,092	63.35	1.87%
13	Total Uniform Tariffs		515,106	13,088,479,157	$1,059,476,824	80.95	$16,345,315	$1,075,822,140	82.20	1.54%
14	Special Contracts:									
15	Micron	26	1	473,329,675	$24,487,522	51.73	$528,311	$25,015,833	52.85	2.16%
16	J R Simplot	29	1	192,166,897	$9,307,187	48.43	$213,058	$9,520,245	49.54	2.29%
17	DOE	30	1	201,844,932	$9,844,014	48.77	$230,608	$10,074,621	49.91	2.34%
18	Total Special Contracts		3	867,341,504	$43,638,723	50.31	$971,977	$44,610,700	51.43	2.23%
19	**Total Idaho Retail Sales**		**515,109**	**13,955,820,661**	**$1,103,115,547**	**79.04**	**$17,317,292**	**$1,120,432,839**	**80.28**	**1.57%**

[1] June 1, 2016, through May 31, 2017, forecasted test year.

Attachment C
Case No. IPC-E-16-08
Staff Comments
05/19/2016

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 19th DAY OF MAY 2016, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF** IN CASE NO. IPC-E-16-08, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Rupa Quintero
SECRETARY